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Evaluating the Profitability of Natural Gas Combustion Turbine Power Plants in the US and its Implications on Future of Natural Gas as a Bridge Fuel for Electricity Generation

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EVALUATING THE PROFITABILITY OF NATURAL GAS COMBUSTION TURBINE POWER PLANTS IN THE US AND ITS IMPLICATIONS ON FUTURE OF NATURAL GAS AS A BRIDGE FUEL FOR ELECTRICITY GENERATION

BY

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ABSTRACT

Investment in electricity generation infrastructure has been long lived because of its high lead times and high capital cost. In addition to its long-lived nature, the investment has also become riskier with the deregulated market structure and high electricity price volatility. The push towards building generators with flexible generation, low capital cost and low lead times has driven the investment towards natural gas fired generation resulting in large amount of capacity addition in the 2000s. Natural gas fired generation technologies have different economics compared to other technologies. In this study we find that as most of the cost of a natural gas power plant is the fuel cost and with natural gas being cheap, natural gas fired technologies pay back sooner than other technologies. Analysis of NGCT plants' economics in six locations (New York City, Chicago, Houston, Long Island, Washington D.C. and Dunwood, NY), show that payback periods range from 9 to 17 years, depending on region the plant is operating in. This payback period is shorter than other generation technologies such as coal and nuclear. We also discuss how this high profitability and short payback period of NGCT power motivates investment in natural gas fired generation and the need policy to direct the investment towards cleaner generation technologies.

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1. BACKGROUND

Electricity is one of the most versatile and consumed sources of fuel. In 2017, 28% of the residential, commercial and industrial final energy demand was satisfied by electricity and 38% of all the primary energy was used for electricity generation (LLNL 2018). As more sectors of economy, like transportation, get electrified the demand for electricity is bound to increase even more. The aging electricity infrastructure and push towards low carbon generation is attracting huge sums of investment in the electricity sector.

Even in the past, Electricity generation infrastructure has attracted huge sums of investment. Most electricity generation infrastructure have high capital cost, high lead times and inflexible operation. This results in long payback period of the infrastructure which is spread out through most of the lifetime of these technologies. The payback period of a nuclear power plant is about 40 years including lead times (Kharitonov, V. V. et al. 2017) and that of an Integrated Gasification Combine Cycle (IGCC) coal fired power plant with CCS is about 22 years (Tola et al. 2014) excluding lead time which is 6-8 years (NETL 2010). Moreover, conventional generation technologies also require supporting infrastructure like coal mines, oil and gas fields and pipelines etc. which tend to have a longer lifetime than the generation infrastructure itself. The long lifetime of supporting infrastructure and slow payback of some generation assets makes electricity a long-lived investment.

In addition to its long-lived nature, investment in electricity generation infrastructure has become riskier over the years as electricity markets have been restructured. In the regulated markets, the utilities would make large investments in high capacity infrastructure. As utilities were vertically integrated monopolies they controlled the price customers paid for electricity. This allowed the risks involved in investment in electricity generation infrastructure to be transferred to the customers in the form of increased price for electricity. It also decreased the risk of investment in electricity generation for the utilities and the financers. Utilities in turn received capital at a lower interest rates and made large investments in high capacity electricity generation infrastructure.

Unlike in the vertically integrated market structure, the market risks have been internalized in the restructured markets as the costs can no longer be passed on to the consumers (OECD 2003). The percentage of renewable energy generation capacity is rapidly increasing. Increased penetration of renewable energy lowers the price of electricity as they have low marginal cost and pushes the base load generators with high marginal cost out of the market. Most of the generators with high marginal cost are conventional generators as the fuel to run them is expensive (Kirch 2018). This further elevates the risk related to investment in electricity infrastructure. Moreover, the electricity prices in a competitive market structure are more volatile. This volatility in the electricity prices is a risk for generators with low ramp rates like coal and nuclear generators as they cannot change the output as fast as the fluctuations in price.

In recent years, natural gas has taken over coal as a major fuel for electricity generation. In 2017, 32% of the electricity generated was using natural gas as compared to 30% using coal (EIA-

Electricity Explained 2017). By 2050 natural gas fired generation will contribute to 45% of the total generating capacity and 35% of the total generation (EIA-AEO 2018). The reason for this transition to natural gas from coal is that natural gas fired generation is economically and technically better than coal in the current market. Unlike coal and nuclear plants, natural gas generation technologies have lower capital cost and low lead times. This results in lower financing cost and the plants can start operating and generating revenue sooner. As the natural gas turbines have high ramp rates, natural gas power plants can operate flexibly and can alter the generation based on market signals more easily. This also lowers startup cost. Use of gas turbines in jet engines has led to accelerated technological innovation in turbine technology and substantially increased its efficiency (Hirsh 1999). In addition to this, cheap natural gas lowers the marginal cost of the generator and increases the overall profit as it can generate electricity at a lower cost and operate at higher capacity factors. Natural gas has become the non-renewable generation of choice since early 2000s. Investment in natural gas capacity has continued since then and it is considered to be a bridge fuel between older carbon intense infrastructure and future carbon free infrastructure.

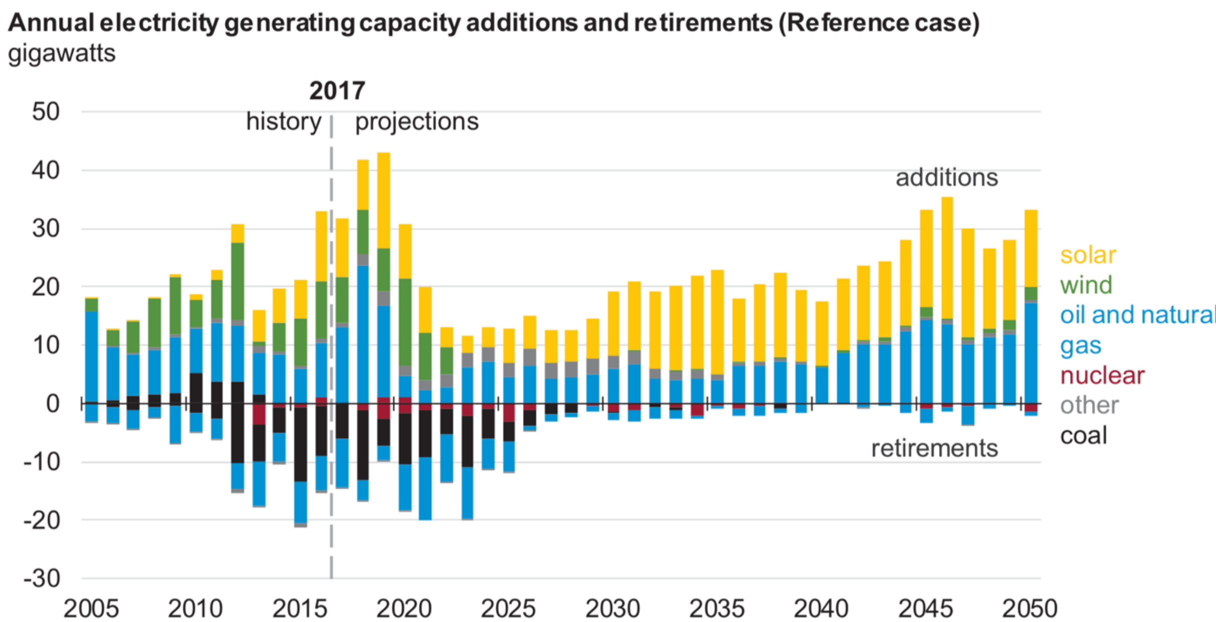

FIGURE 1: *Electricity generation capacity addition by technology in the united states from 2005 to 2050 as represented in the Reference Case Scenario of Annual Energy Outlook-2018. Most of the capacity built in the 2000s was Natural Gas fired, and the trend is likely to continue with more natural gas fired capacity additions in the future.*

As investment in natural gas fired generation infrastructure increases, and more natural gas capacity is built, it will be one of the major, if not the only source of emissions from electricity generation in the future. This increases the likelihood of lock-in of carbon intense infrastructure for decades. Average age of power plants in the United States is about 30 years. According to EIA about 88% of the coal fired generation capacity operating as of December 2016 was built between 1950 and 1990. Also, the capacity-weighted average age of coal fired capacity in operation was 39 years. According to a study by (Pfeiffer et al. 2016), no new electricity generation infrastructure must be built after 2017, unless it is a replacement for older retiring infrastructure or is coupled with carbon capture technologies, to meet the emission targets. This estimate is under the assumption that other sectors of the economy meet their emission targets to limit global temperature increase to 2 degrees. Any investment in conventional electricity generation technologies today, drives us off the path to meet climate targets. Hence, there is a dire need to shorten the bridge between conventional generation and renewables and transition to low carbon generation sooner.

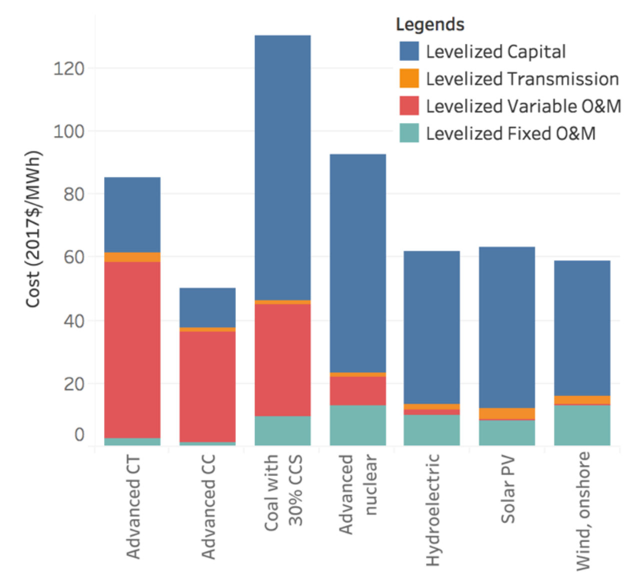

FIGURE 2: *Levelized cost of electricity generation of different technologies split into the individual components. It highlights the difference between economics of natural gas fired technologies and other conventional technologies. Variable O&M cost (which includes the fuel cost) account for majority of the cost of electricity from natural gas fired plants whereas, capital cost contributes to majority of the cost for other technologies.*

We believe that, as natural gas fired power plants have different economics compared to other technologies, not all investment in electricity generation is the same. Investment in natural gas combustion turbine (NGCT) power plants can be recovered sooner than other conventional electricity generation technologies. EIA publishes Levelized cost estimates as represented in the NEMS for Annual energy outlook. The distribution of cost over different components varies for different technologies. The natural gas fired technologies have relative lower capital cost but high variable cost. On the other hand, coal, nuclear and hydro have higher capital cost and lower variable cost and renewables have no variable cost. Natural gas plants have low capital cost, most of its cost is the fuel cost and they are flexible to operate. With natural gas being cheap and market mechanism tipping in favor of natural gas plants, they must be more profitable than almost any other generation technology.

There is extensive literature about economic performance, profitability, payback of electricity generation technologies. Studies like Botterud et al. 2007 and Conzelmann et al. 2005 do complex modeling to simulate the electricity markets to predict future profitability and inform capacity expansion planning. But, in these studies there is not much emphasis on the historical performance of the plants. Other studies like Falode et al. 2016 calculate the NPV, IRR and payback of powerplants by making assumptions for capacity factors. This does not capture the demand supply dynamics and the price volatility of the competitive markets. A 200l study (LCC 2001) by LCC Consulting, estimated the contribution of revenue from ancillary services to the overall revenue of powerplants based on historical market data for one year but was not focused on estimating the payback period.

Hence, to test the hypothesis, we built a model of a natural gas combustion turbine power plant operating in the US electricity markets to estimate the historical revenue the plant would have made using the market price data and other market operation data. Using the revenue calculated we estimate the payback period of a typical NGCT power plant and discuss its implications on future of investment in electricity generation.

2. METHODOLOGY

A NGCT powerplant, which is a peaker plant, can generate revenue from various streams in restructured markets. It can generate revenue by participating in the energy markets, providing ancillary services or in the form of capacity payments. We base our model on a NGCT power plant operating with perfect market information. It means that the plant has all the information it needs to determine which service is most profitable in any given hour and it will opt to provide that service. Following table shows the assumptions used to model the power plant.

TABLE 1: *Model assumptions for characteristics of Natural Gas Combustion Turbine Power Plant*

Characteristics of Model NGCT Power Plant		
Name Plate Capacity	50 MW	Model Assumption
Capital Cost	676 $/kW	EIA 2010
Fixed O&M Cost	7.04 $/kW	
Variable O&M Cost	10.37 $/kWh	
Heat Rate	9.750 BTU/kWh	EIA-EPA 2016
Lifetime	40 years	Model Assumption
Minimum Operating Load	20 MW	Model Assumption

We use historical market operation data including, clearing prices, fuel costs and O&M cost to determine the profitability of providing different services in any given hour. Using the profitability information, we determine the best utilization of plant capacity to maximize overall profit in that hour. We assume that the plant can provide only one service in any given hour. To determine the profitability, we model the cost and revenue of participating in the energy market and providing different ancillary services in ERCOT, PJM and NYISO. To provide any of the services the ISOs carry out uniform price auctions where plants place their bids and depending on the demand for that service the market clearing point (which is the cost of the plant on the margin) determined. All the bids below the market clearing point are accepted and the plants are compensated accordingly. However, as different services have different market mechanisms and characteristice, we model each service separately and aggregate the hourly cost, revenue and profit for every year the plant is in operation. Using the annual cost, revenue and other information like capital cost we estimate the payback period of the plant.

2.1 Energy Markets

All the deregulated markets operate energy markets. The energy markets work on a fundamental principle which is to procure enough electricity supply to satisfy the demand at the least cost possible. The ISOs procure energy from generators based on their marginal cost of generation which generators bid as the cost of electricity. The ISO procure electricity from generators in increasing order of their marginal cost, i.e. ISO will buy cheapest electricity first (generators like coal, hydro, renewables) and most expensive electricity last (generators like natural gas, petroleum), until there is enough to satisfy the demand. Hence, higher the demand more is the price of electricity. Unless there is enough demand to get the price of electricity up to the marginal cost of a power plant that plant will not be able to generate and sell electricity.

We use a methodology based on the above principal to model the energy markets in all the regions. If the locational marginal price of energy is higher than or equal to the marginal cost of the NGCT plant in a particular hour the power plant will generate and sell all of its electricity in the energy market if the locational marginal price is lower than the marginal cost the plant will participate in the ancillary services market and provide the most profitable service. We also assume that the plant is always a price taker and is never on the margin. Hence, whenever the plant is in operation it will operate at full capacity unless it is providing ancillary services. We assume energy market to be the base of the revenue stream and that the plant will always participate in energy markets when it is not making a loss.

We estimate the marginal cost per MWh for every hour (operating cost) and every location using the equation 1. The marginal cost for each hour in a particular month is the same because the fuel cost data is only available at a monthly frequency.

$$Marginal\ Cost_h = \left[\frac{Fuel\ Cost_h}{1.013} \times Heat\ Rate\right] + (Variable\ O\&M\ \times Location\ Correction) \tag{1}$$

The annual revenue from energy markets is calculated using equation 2a which is based on the principal described above, and the variable cost is calculated using equation 2b.

$$Annual\ Revenue_{Energy}\ (\$) = \sum_{h=0}^{8760} \begin{cases} 50\ \times Locational\ Marginal\ Price_h, & Locational\ Marginal\ Price_h \geq Marginal\ Cost_h \\ 0, & Locational\ Marginal\ Price_h < Marginal\ Cost_h \end{cases} \tag{2a}$$

$$Annual\ Total\ Variable\ Cost_{Energy}\ (\$) = \sum_{h=0}^{8760} \begin{cases} 50\ \times Marginal\ Cost_h, & Locational\ Marginal\ Price_h \geq Marginal\ Cost_h \\ 0, & Locational\ Marginal\ Price_h < Marginal\ Cost_h \end{cases} \tag{2b}$$

2.2 Ancillary Services

All ISOs operate ancillary services markets in addition to energy markets to ensure reliable operation. FERC defines ancillary services as "those services necessary to support transmission of electric power from seller to purchaser, given obligations of control area and transmitting utilities within those control areas, to maintain reliable operations of the interconnected transmission system" (FERC 2016). It classifies the ancillary services into 6 main categories. Reactive power-voltage regulation, system protective services, loss compensation services, system control, load dispatch services and energy imbalance services. In this model, we include only 2 of the above categories. Reactive power-voltage regulation which includes the regulation services (regulation up and regulation down in case of ERCOT) and energy imbalance services which include spinning and non-spinning reserves. Ancillary services contribute to a substantial portion of revenue for a peaker natural gas power plant.

NYISO provides five ancillary services. Regulation, 10-min Spinning reserve, 10-min non-spinning reserve, 30-min spinning reserve and 30-min non-synchronized reserve (NYISO-AS 2018). ERCOT operates four ancillary services. They are called Responsive Reserves, Regulation-up, Regulation-down, and Non-spinning reserves (ERCOT-AS 2010). PJM operates three ancillary services. They are Regulation, Synchronized Reserve and Primary Reserve. Depending on the ISO, the ancillary service operations are divided into zones within that region. NYISO divides the area into 3 zones, which are, West of Central-East, East of central east and long island (NYISO-AS 2018) for all ancillary services. All the area served by ERCOT is treated as a single zone for all ancillary services. Synchronized Reserve and Primary Reserve markets in PJM region are divided into two zones. The PJM territory and the PJM Mid Atlantic Dominion (MAD) Sub Zone. For the regulation market all of PJM region is considered as a single zone (PJM-AS 2018).

As different ISOs have different ancillary services, we model the revenue for each individual ISO based on the market structure and locational data. Our model for ancillary services is based on the assumption that, when not serving the energy market, the plant will provide the most profitable ancillary service operated by the RTO in any given hour. We then aggregate the hourly revenue and variable cost for every year. We calculate the cost and the revenue of each ancillary service in a given hour using market data to calculate the profit and use it as a decision criterion to choose an ancillary service in that hour.

2.2.1. Non-Spinning Reserves

Non-spinning reserves which is also called as Non-synchronized reserves is a type of operating reserve service provided by generators which are off line. The generator does not have to be actively generating electricity but must be able to start operation and generate electricity in an amount of time specified by the ISO. The NYISO provides two types of non-spinning reserve services, the 10-min Non-spinning reserve and 30-min Non-synchronized reserve. ERCOT operates only one market for Non-spinning reserve services which is called Non-Spinning Reserves and so does PJM which is called Primary Reserve.

If the plant chooses to provide Non-spinning reserve in any particular hour, in which case it will be the most profitable service in that hour, it will bid all of its capacity for that service. We calculate the revenue from Non-spinning reserve which is a product of the bid capacity and the Non-spinning reserve clearing price in that hour using equation 3a. As the plant does not have to generate to provide this service, the operating cost is minimal or close to zero. If the plant is called to provide electricity, it implies that the demand for electricity is high enough for the locational marginal price to be higher than the marginal cost of the power plant. In that case the plant will have participated in the energy market. In case of NYISO which operates two non spinning reserve services, we only account for the revenue from the service which has the highest clearing price in any given hour.

$$Revenue_{Non\ Spinning\ Reserve_h} = 50 \times Non\ Spinning\ Reserve\ Clearing\ Price_h \tag{3a}$$

$$Variable\ Cost_{Non\ Spinning\ Reserve_h} = 0 \tag{3b}$$

2.2.2. Regulation

Regulation services are operated to maintain the balance between supply and demand over a very short period of time (over few seconds). The plant has to change its output to match the Automated generation Control (AGC) signal provided by the ISO. To provide this service the generator has to be running at a certain capacity depending on the type of regulation market and change its output when required to do so.

NYISO and PJM operate only one market for regulation which serves both regulation up and regulation down requirement. In this case, the model 50 MW powerplant can provide only 15 MW of regulation service. As the minimum operating load of the plant is 20 MW and as the plant can be called to provide either regulation up or regulation down, it has to operate at 35 MW so that it can ramp-up and provide 15 MW regulation up or ramp-down and provide 15 MW regulation down. In addition to providing regulation services, the plant sells the electricity generated by operating at 35 MW capacity in the energy markets which adds to the revenue from energy markets. The plant will generate electricity and sell it in the electricity markets even if it is losing money as long as the overall operation of providing regulation service is profitable. If the plant chooses to provide regulation service in any particular hour, we calculate the revenue in that hour for NYISO and PJM using equation 4a. The variable cost of providing regulation services is the cost of operating at 35MW and generating electricity while the plant is bidding for regulation and is calculated using equation 4b.

$$Revenue_{Regulation_h} = 35 * Energy\ Market\ Clearing\ Price_h + 15 * Regulation\ Clearing\ Price\ _h \tag{4a}$$

$$Variable\ Cost_{Regulation_h} = 35 \times Marginal\ Cost_h \tag{4b}$$

Unlike the NYISO and PJM, ERCOT operates two regulation markets, one for providing regulation up and other for providing regulation down. The plant has to either ramp down to provide regulation down or ramp up to provide regulation up. As the two markets are separated the plant can bid more capacity for regulation as it can be called to ramp only in one direction. In this case it can bid 30 MW. Hence, we model the two regulation services similar to regulation in NYISO but separately as the plant will be operating at different load depending on the service it has bid for.

a) To model regulation down, we assume that the plant is operating at full capacity (50MW) and bidding for 30MW of regulation down. It can only bid 30MW of capacity into the regulation down market as it has to operate at a minimum operating load of 20 MW at all times. During this time, it is selling all of the electricity generated while operating at full capacity into the energy markets. We calculate the revenue and the cost of providing Regulation-Down in any particular hour using equation 4c and 4d.

$$Revenue_{Regulation-Down_h} = 50 * Energy\ Market\ Clearing\ Price_h + 30 * Regulation\ Down\ Clearing\ Price\ _h \tag{4c}$$

$$Variable\ Cost_{Regulation-Down_h} = 50 \times Marginal\ Cost_h \tag{4d}$$

b) To model regulation up, we assume that the plant is operating at minimum operating load (20MW) and bidding for 30 MW of regulation up service. During this time, it is selling all of the electricity generated while operating at minimum operating load into the energy market. We calculate the revenue and the cost of providing Regulation-Up in any particular hour using equation 4e and 4f.

$$Revenue_{Regulation-Up_h} = 20 * Energy\ Market\ Clearing\ Price_h + 30 * Regulation\ Up\ Clearing\ Price\ _h \tag{4e}$$

$$Variable\ Cost_{Regulation-Up_h} = 20 \times Marginal\ Cost_h \tag{4f}$$

2.2.3. Spinning Reserve

Spinning reserve services are provided by generators which are running and are able to increase their output in a certain amount of time specified by the ISO which is generally lower than non-spinning reserves and is about 10-15 minutes in most markets.

NYISO calls its spinning reserves 10-Min Spinning Reserve, ERCOT calls it Responsive Reserve and PJM calls it Synchronized Reserve. Despite different names all of the services are fundamentally similar and hence we take the same approach to model them. To qualify for spinning reserve service, plant has to be operating at minimum load at all times. Hence, we assume that if the plant provides spinning reserves, it will be operating at 20 MW as it is the minimum load. It will bid the rest of the capacity which is 30MW in this case into the spinning reserve market. Similar to regulation services, the plant will generate electricity and sell it in the electricity markets even if it is losing money so long as the overall operation of providing spinning reserves is profitable. We calculate the revenue and the cost of providing spinning reserve service using equation 5a and 5b respectively.

$$Revenue_{Spinning\ Reserve_h} = 20 * Energy\ Market\ Clearing\ Price_h + 30 * Spinning\ Reserve\ Clearing\ Price\ _h \tag{5a}$$

$$Variable\ Cost_{Spinning\ Reserve_h} = 20 \times Marginal\ Cost_h \tag{5b}$$

2.3 Capacity Payments

NYISO and PJM both operate capacity markets to ensure adequate generation capacity is available to satisfy the current and future demand at all times. Capacity markets are not only supposed to ensure short term resource adequacy but also aid capacity expansion and investment in new generation capacity. In the capacity markets, the load serving entities are either required to meet the capacity requirement set by the RTO by either supplying the capacity themselves or procuring it or the RTO procures the capacity and allocates the cost to the LSEs. The payments to generators to ensure they are available to operate when required, add to the revenue of a generator.

NYISO operates a capacity market called Installed Capacity (ICAP) Market. The load serving entities (LSEs) in NYISO are required to fulfill their obligation to procure enough capacity to meet their minimum requirements. The capacity requirements for each LSE are calculated based on the forecasted peak demand it would have to serve in and an additional installed reserved margin. NYISO conducts auctions to facilitate LSEs to procure installed capacity from installed capacity suppliers. NYISO operates the ICAP market in two periods in a year, called the Summer Capability Period and the Winter Capability period. For each period, they conduct three auctions, the capability period auction (also called as the strip auction) which is no later than 30 days before the start of a capability period, the monthly auction which is conducted every month within a capability period, and the spot auction which is conducted at the start of each obligation procurement period (NYISO-CAP 2018). We use the strip auction clearing price data which is price for unit capacity per day for both the capability periods and aggregate it annually to calculate the annual capacity payments for 50MW generator. As the winter capability period is always split between two years as it goes from November of a particular year to April of next year, we also split the capacity payment accordingly depending on number of days in each year for which the auction prices apply.

PJM ensures adequate generation capacity through two market structures which are based on Resource Pricing Model (RPM) and Fixed Resource Requirement (FRR). LSEs can opt for either of the two to ensure adequate generation capacity. However, the capacity markets in PJM are based on RPM. The RPM is used to determine the locational capacity pricing, variable resource requirement mechanism, forward commitment of supply and reliability backstop mechanism. RPM consist of a base residual auction and up to three incremental auctions after the base auction for each delivery year. The base residual auction is held in the month of May three years before the delivery year and the incremental auctions are held between the base residual auction and the delivery year (PJM-CAP 2018). The FRR alternative on the other hand requires LSEs to submit fixed resource capacity plan and meet the resource requirements. FRR alternative is more suitable for entities operating out of market and getting their revenue from out of market (e.g. through PPAs) and RMP is more suitable for entities participating in the competitive markets (e.g. market settlements) (Pfeifenberger et al. 2009). Since all of revenue of the NGCT plant in consideration is from competitive markets we consider capacity payments only through RPM. We use the base residual auction clearing price data for each delivery year which is price for unit capacity per day and aggregate it annually to calculate the annual capacity payments for a 50MW generator. A planning period in PJM is a 1-year period from June 1 of a particular year to May 31of the next year. Hence, we account for the capacity payments accordingly depending on number of days in a calendar year for which the auction prices apply.

2.4 Calculating the rate of payback

We use the capital cost, fixed cost and variable O&M cost data for each region from Capital Cost Estimates for Utility Scale Electricity Generating Plants data by EIA. Using the model outputs and the EIA cost data we calculate the profit generated by the plant in each year. To calculate the annual loan payments, we assume the that all of capital cost is a one-time inflow of cash. The capital cost has to be paid back with interest over the lifetime of the plant. We assume that the loan is the overnight capital cost of the plant which grows at 6.97% per year (compounded annually) (FRB 2017). All of the profit generated is directed towards paying back the capital cost of the plant. If the plant makes a profit after paying off the nominal loan payment, the principle diminishes faster than the nominal duration of the loan based on amortized loan calculation, if the plant makes a loss the principle diminishes slower.

We extrapolate the annual outstanding principal and estimate the breakeven point where the outstanding principal is zero.

3. Data Sources

TABLE 2: *Sources of data used as inputs to the model*

Variable	ISO	Data Source	Time Horizon
Locational Clearing Price electricity	NYISO	NYIOS-RTP n.d.	2007-2016
Ancillary service market price		NYISO-RTAS n.d.	2007-2016
Capacity payments		NYISO-ICAP n.d.	2007-2016
Natural gas price		EIA-NG-NY n.d.	2007-2016
Locational Clearing Price electricity	PJM	PJM-RT n.d.	2007-2017

Ancillary service market price		PJM-RTAS n.d.	2012-2017
Capacity payments		PJM-CPM, n.d.	2007-2017
Natural gas price		EIA-NG-DC n.d.	2007-2017
		EIA-NG-IL n.d.	
Locational Clearing Price electricity	ERCOT	ERCOT-RT n.d.	2012-2017
Ancillary service market price		ERCOT-RTAS n.d.	2012-2017
Capacity payments		No Capacity Market	-
Natural gas price		EIA-NG-TX n.d.	2012-2017
Cost Data (Capital cost, variable O&M cost, fixed cost, location correction)		EIA 2010	2007,2012
Interest Rate		FRB 2017	2007, 2012

4. Results

The model calculates hourly revenues from providing energy and ancillary services and aggregates them annually. Figure 3 shows sample of NGCT powerplant operations and the hourly revenue from Energy, Non-spinning Reserves, Spinning Reserves and Regulation for ten days in March 2016 for PJM. It also shows the hourly energy clearing price during that time. The hourly revenue and the cost for each service is aggregated annually to yield results shown in figure 4.

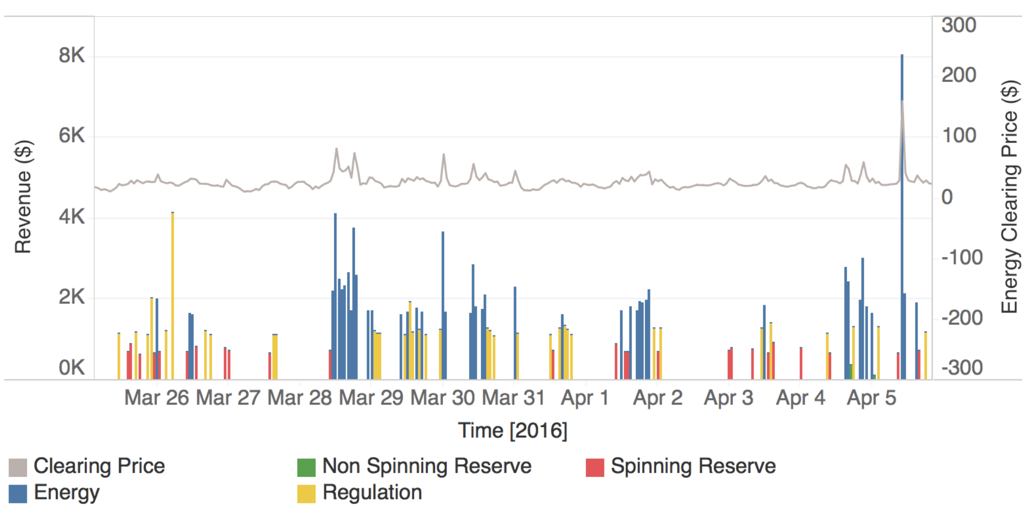

FIGURE 3: *Sample model output showing hourly revenue from energy, non-spinning reserve, spinning reserve, and regulation and hourly clearing price for ten days in March 2016 for PJM*

Table 3 shows the utilization of a NGCT power plant operating in Washington DC as estimated by the model. Due to lack of data for earlier years in PJM the model does not estimate the utilization of the plant for ancillary services. As an NGCT power plant is a peaker plant, it is off-line for most of the time. When the plant is in operation it participates in the energy market for most of the time follow by regulation and spinning reserve. Other regions also show similar utilization of the power plant.

TABLE 3: *Utilization of the NGCT plant in PJM-Washington DC for various services represented as percentage of hours in a year and the capacity factor.*

	PJM-Washington, DC				
Year	Off-line/Non-spinning Reserves (% of hours in a year)	Energy (% of hours in a year)	Spinning Reserve (% of hours in a year)	Regulation (% of hours in a year)	Capacity Factor (%)
2007	76.3	23.7	-	-	23.7
2008	83.4	16.6	-	-	16.6
2009	90.8	9.2	-	-	9.2
2010	82.4	17.6	-	-	17.6
2011	87.8	12.2	-	-	12.2
2012	85.1	11.0	1.6	2.4	13.3
2013	81.3	8.8	1.9	8.0	15.2
2014	70.4	17.2	2.0	10.3	25.3
2015	56.7	21.5	6.0	15.8	35.0
2016	62.7	22.2	4.7	10.4	31.4
2017	66.3	25.5	3.0	5.2	30.4

As shown in figure 4, variable cost accounts for most of the plants' cost. As most of the variable cost is fuel cost, the variable cost was considerably higher when natural gas was expensive during around 2007 and as natural gas became cheaper the variable cost decreased considerably. Other costs include fixed O&M cost which is constant over the years and capital cost which is a significant amount and is varies with location and terms of loan.

Energy markets contribute to the majority of the revenue generated by the NGCT power plant, followed by ancillary service markets and capacity markets (if available). This trend is consistent across all the regions. The energy market on an average is more profitable than ancillary services markets. The revenue from ancillary services in NYISO has significantly decreased over the years and the capacity payments have increased. In PJM however, there is not a lot of variation. ERCOT does not run capacity markets. But, the revenue to cost ratio of the energy market in ERCOT is significantly higher compared to other ISOs. Because electricity prices are higher in ERCOT, the plant earns more from the energy markets.

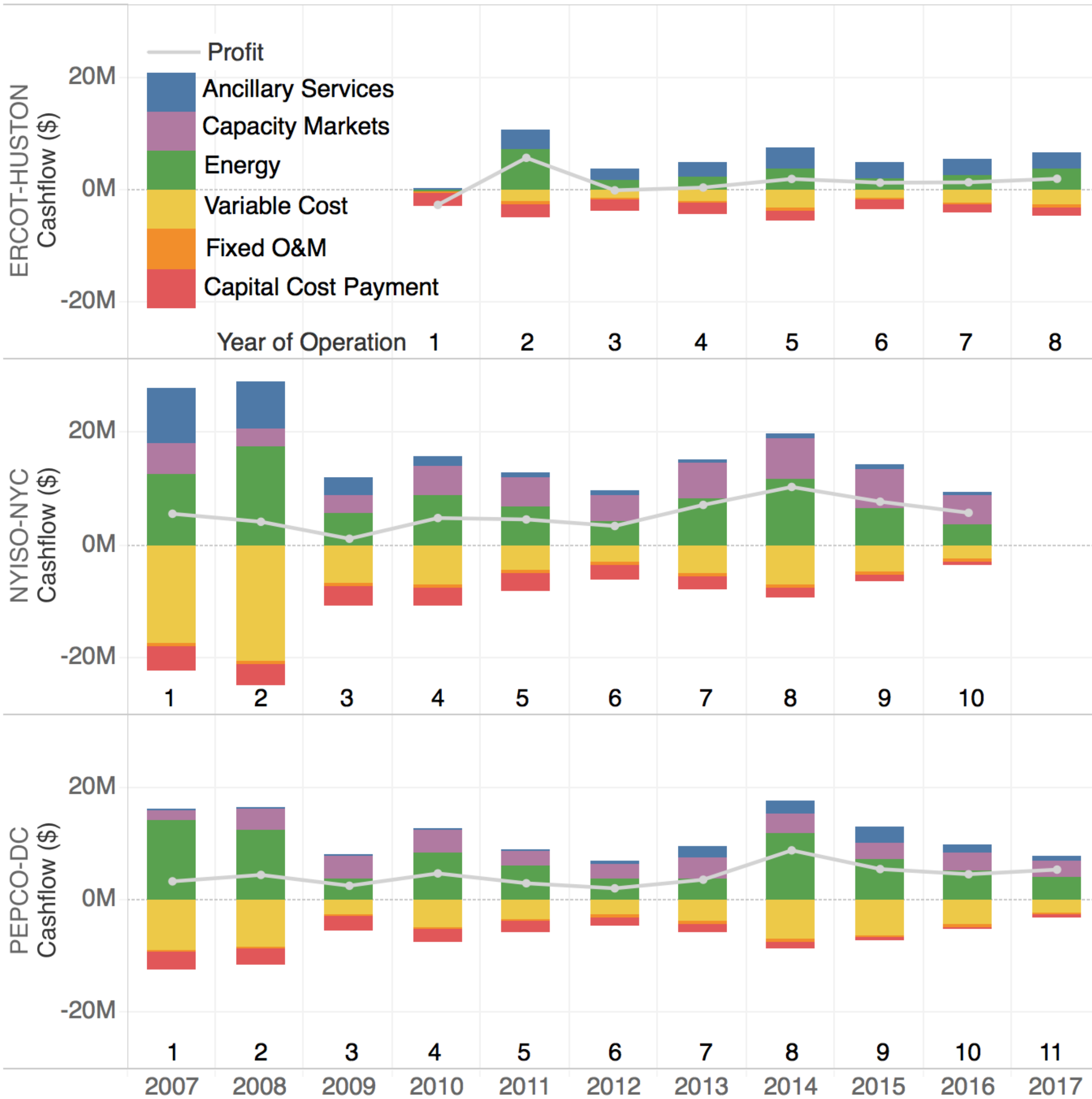

FIGURE 4: *Cash flow of 50MW Natural Gas Combustion Turbine power plant operating in different markets. It shows the revenue from capacity, energy and ancillary services markets as positive values, and the fixed O&M cost, variable cost and capital cost payment as negative values and the profit in each year. It shows that in each of the market the revenue from energy markets and variable cost, most of which is fuel cost, constitute the major portion of the total revenue and total cost respectively.*

Another common trend observed in most markets analyzed is high revenue from energy in 2008 and 2014, a dip in profit in 2009 and a peak in profit in 2014. The revenue from energy markets is high both in 2008 and 2014 which implies high peak electricity demand. However, the Henry Hub Natural Gas price in 2008 was 8.86 $ per million BTU as opposed to 4.37 $ per million BTU in

2014 (EIA-NG n.d.). This difference in fuel price explains the high profit in 2014 compared to 2008 despite high revenue. On the other hand, the natural gas price in 2009 was 3.94 $ per million BTU which is lower than that in 2014 (EIA-NG n.d.). The profit in 2009 should have been comparable to that in 2014. But it was not the case because low demand for electricity due to economic recession did not increase the price of electricity enough to benefit NGCT plants. Hence, both high peak electricity demand and low natural gas prices are crucial for profitability of NGCT power plants.

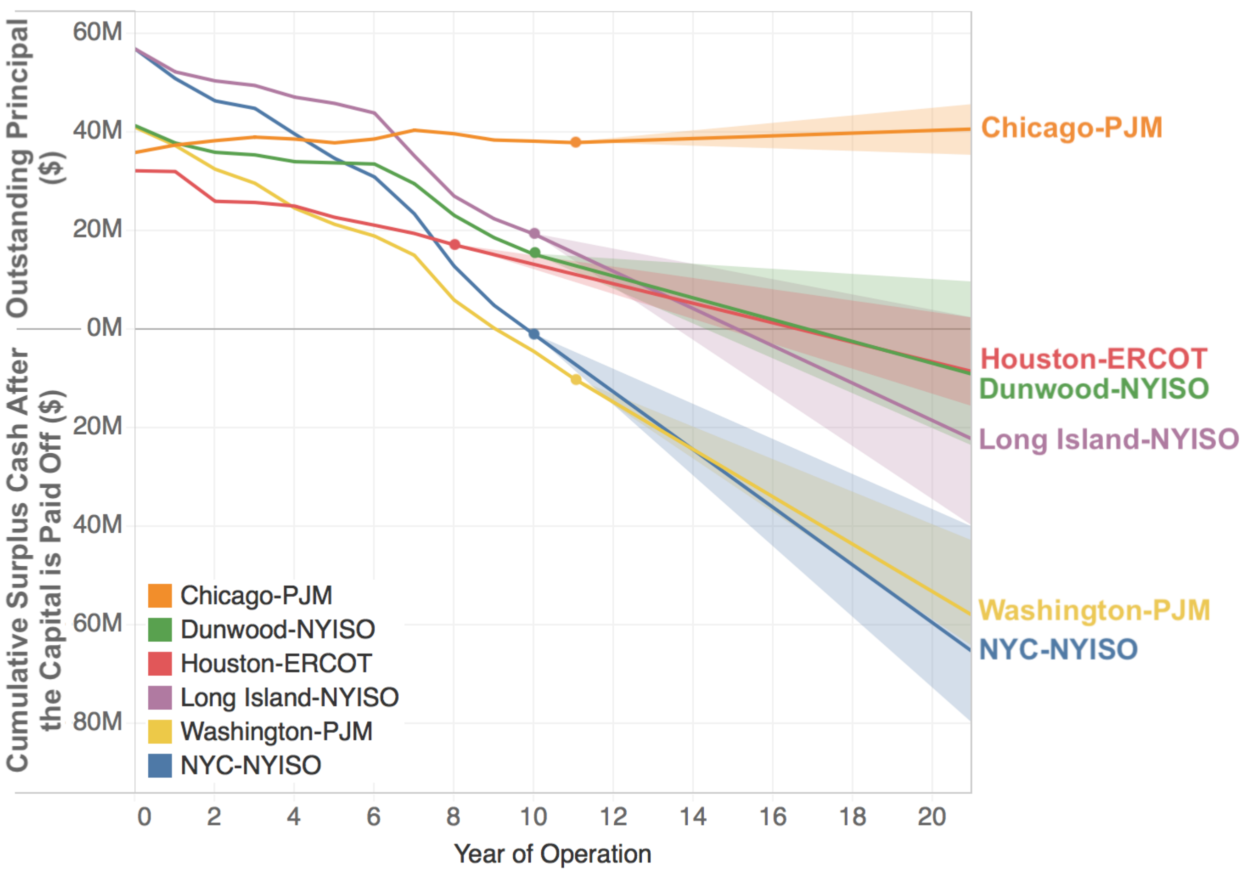

FIGURE 4: *Rate of payback of capital for plants operating in different regions and the cumulative surplus cash after the plant has paid back its capital investment. The rate of pay back depends on the region the plant operates in and most locations have payback period between 9-17 years which is lower than other technologies. The dots in the time series represent the separation between historical data and forecast.*

The rate at which the capital can be paid back depends on the cost and revenue of the powerplant which depend on the location the plant is operating in. As figure 4 shows, the payback of capital cost follows a linear trend which implies consistent profitability but the rate at which the capital is paid back differs with the region. The plants in NYC-NYISO, Washington-PJM and Houston pay back the capital cost in a short 9 to 17 years' timeframe. Because of high peak demand in NYC-NYISO and Washington-PJM the plant can participate in the energy market more often, operate at a higher capacity factor and because of cheap fuel price it can earn more profit. In Houston the high payback is a result of low capital cost in addition to high electricity prices. The high energy prices compensate for the lack of capacity markets in Houston-ERCOT to some extent. The plants operating in Chicago-PJM does not seem to be profitable. The low profitability can be attributed to low revenue from energy markets.

Most companies which own power generation assets have multiple assets in different locations. The plants considered for analysis in this study can be thought of as one of the many portfolio of assets owned by a company. Investment in plants in NYC and Washington, DC were less risky part of the portfolio and performed well whereas, investment in Chicago was a more riskier part of the portfolio and performed poorly. Aggregating the performance of the individual assets to estimate the performance of the portfolio shows the payback period of the portfolio to be about 15 years and average profitability of 38% over 10 years. For reference, the yield of a 10 year U.S. treasury bond is 2.8% which shows that investment in NGCT power plants is highly profitable.

Hence, it can be concluded that investment in NGCT powerplant can be recovered sooner because of the lower capital cost, low fuel cost and the revenue generated from energy, ancillary service and capacity markets. Also, consistent profitability indicates that the investment is comparatively less risky than other generation technologies.

5. Payback Period in Chicago-COMED

Since Washington, DC and Chicago both are a part if PJM, comparing the economics of both the locations might help understand the huge difference in profitability and payback period. The major reason for low profitability of plants operating in the Chicago area is the low revenue from the energy market. In 2016, the total generation in Chicago-COMED was 129,371 GWh when the load was 98,002 GWh. On the other hand, the total generation in PEPCO was 10,135 GWh when the load was 30,339 GWh. The 2017 Quarterly State of the Market report from PJM attributes the low revenue to reliability requirements enforced by external regulatory authority which requires a certain level of installed capacity (PJM-SOM 2017). According to the report, these requirements result in excess generation capacity compared to the demand and lower the locational marginal prices and eventually the revenue. As COMED has higher generation than the demand unlike PEPCO, these requirements affect the plants in the COMED area significantly compared to PEPCO.

In addition to the reliability requirements the high transmission congestion in the PEPCO area increases the locational marginal prices and hence the revenue, whereas the relatively congestion free transmission in the COMED area keeps the locational marginal prices low. In 2016 the load weighted average locational marginal price in COMED was $ 27.66 which had a congestion component of -$0.51 whereas that in PEPCO was $34.12 and had a congestion component of $4.11. Both the regions had similar energy component to locational marginal price, which was $29.11 in COMED and $29.42 in PEPCO (PJM-SOM 2017). Hence the low congestion in the

COMED region and the excess generation capacity result in low revenue and low profitability of plants in COMED area. Building transmission infrastructure to transmit the electricity from COMED to high demand areas or increasing the capacity payments to plants in the COMED area might help the plants offset the losses and become profitable.

6. Sensitivity Analysis

Figure 5 shows the sensitivity of various modeling assumptions (parameters) like Capital Cost, Heat Rate, Variable Cost, Fixed Cost and the Minimum Operating Load. The model results are most sensitive to the Capital Cost. Changes in capital cost have significant effect on the payback period of the power plant. Increase in Capital Cost lengthens the payback period more than the same amount of decrease in Capital Cost shortens it. This is because with high capital cost, there is less profit and the capital cost diminishes slower and vice versa. Hence increase in capital cost has a bigger effect on the payback than decrease in capital cost. The second most important parameter is the heat rate of the plant. Heat rate affects the efficiency of the powerplant and hence the fuel consumption. As fuel cost accounts for the major cost of the powerplant, the overall profit is sensitive to the heat rate of the plant and so is the payback period. Other parameters like fixed cost and minimum operating load have little effect on the payback period.

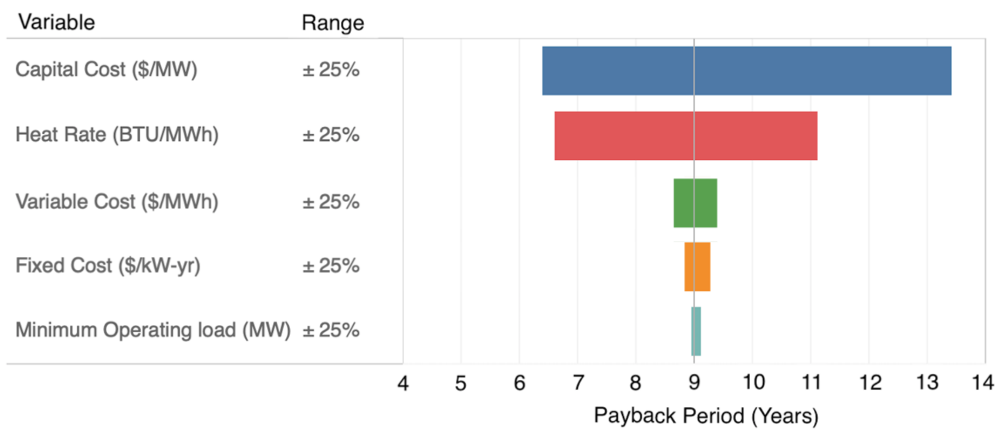

FIGURE 5: *Sensitivity of the model to the modeling assumptions. The payback period of the NGCT power plant is most sensitive to Capital Cost and the Heat Rate of the power plant.*

Figure 6 shows the uncertainty in the assumptions of values of various modeling assumptions and their effect on the modeling results. The range for each variable is estimated using the different values for each parameter appearing in various literature (Capital Cost- NREL n.d., Heat Rate- NETL n.d., Fixed Cost and Variable Cost- Lazard 2017, Minimum Operating Load- Hentschel 2016). Capital cost has a wide range of estimates. That coupled with the high sensitivity of the model to capital cost makes it one of the critical parameters having the most effect on the results. Other parameters despite having high uncertainty in estimates like the fixed cost does not have a strong effect on the results because it contributes to a very small portion of the total cost of the power plant. Hence, Capital Cost and Heat Rate assumptions are the most crucial to the model and have a significant effect on the results.

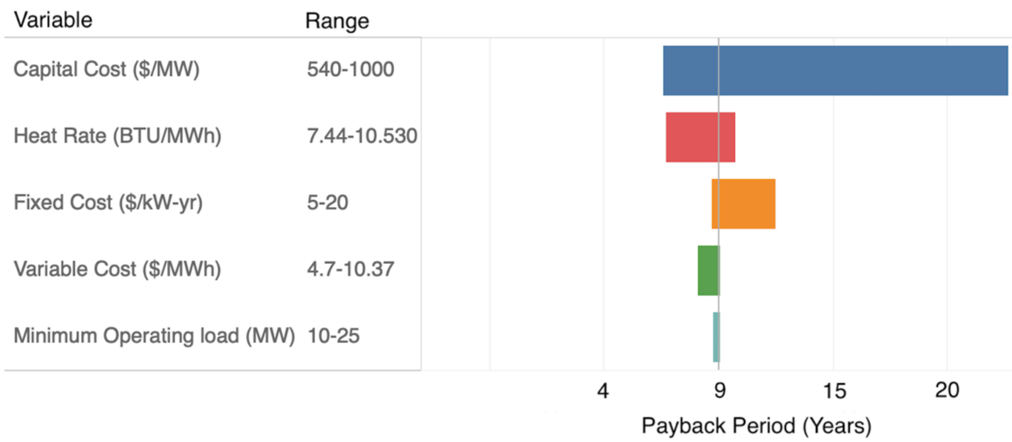

FIGURE 6: *Uncertainty in assumption of parameters and its effect on the payback period. Uncertainty in the capital cost assumptions is the biggest source of variation in the modeling results.*

7. Discussion

Natural gas fired generation is favored by investors because, in addition to having low lead times and low capital cost, cheap fuel also makes these plants cheaper to operate and hence highly profitable. The high profitability of these plants lowers the payback period and accelerates the recovery of invested capital. In absence of an economy wide climate and energy policy, there is a lot of uncertainty around the future of electricity generation. The balance between cheap fossil fuel fired infrastructure and expensive renewable infrastructure to meet the greenhouse gas emission targets is unclear. This may lead to overinvestment in renewable infrastructure which might be under used or underinvestment leading to above threshold carbon emissions (Morris et al. 2018). Such uncertainty calls for short term planning to make it easier to adapt to the ever-changing energy policy and electricity grid. As the short payback period and high profitability of NGCT power plants allows investors to plan for the short term, it has motivated continued investment in natural gas fired generation.

On the other hand, the quickly recovered capital investment from natural gas can be used to accelerate the transition to a cleaner grid. With effective policy measures, the capital can be diverted for other investment may it be new NGCT plants or other technologies like storage. New NGCT power plants can replace the oil powered power plants which have considerably higher emissions or large-scale electricity storage can complement renewables and provide ancillary services. In its current state large-scale energy storage is not economically and technically viable to be deployed at utility level. However, a Green Tech Media study shows that storage will be economically at par with NGCT plants in about five years and more profitable than NGCT in ten years (Manghani 2018). As more natural gas plants breakeven, investors will have a choice to reinvest the freed capital in modern technologies like storage increasing the possibility of investment in low carbon technologies. Even the investment in natural gas plant today will be recovered in 9 to 17 years when low carbon technologies will be ready to be scaled up. Implementing effective policy measures to direct the investment towards cleaner technologies can help accelerate decarbonization of the electricity grid.

NGCT power plants will continue to be more profitable and pay back sooner than most other generation technologies as long as the fuel is cheap and there are no policies to cut the emissions form these plants further. However, the future of electricity generation is uncertain, with penetration of renewables and, social and policy push towards decarbonizing the grid. As natural gas will be one of the major sources of fossil fuel powered generation and hence greenhouse gas emissions in the future, there is bound to be some policy mandate like fuel taxes or greenhouse gas emissions performance standards which will adversely affect the economics of these power plants. Moreover, battery electricity storage when deployed at a large scale will decrease the peak demand and hence decrease the revenue and profitability of NGCT plants. When future policies, regulations and competing generation technologies are deployed, these plants will either have to adapt to bear the increased cost of meeting the policies and regulations and keep running with a pay cut or will be phased out of the market. In either case, as these plants are highly profitable and most of them will have paid off, it will not be as hard a hit to the investors as it otherwise would have been.

If the current investment trends continue, natural gas fired generation will be the only if not the major source of emissions in the future. As long as the fuel is cheap and there is high peak demand, natural gas fire generation will be profitable. Although the high profitability and short payback period motivated continued investment in natural gas fired generation, it can be used to accelerate the transition to renewables and decarbonize the electricity grid with effective policy measures.

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9. Supplementary Information

FIGURE 7: *Cash flow of 50MW Natural Gas Combustion Turbine power plant operating in PJM-COMED, NYISO-Long Island, NYISO-Dunwood. It shows the revenue from capacity, energy and ancillary services markets as positive values, and the fixed O&M cost, variable cost and capital cost payment as negative values and the profit in each year. It shows that in each of the market the*

revenue from energy markets and variable cost, most of which is fuel cost, constitute the major portion of the total revenue and total cost respectively.

TABLE 4: *Utilization of the NCGT plant in NYISO-NYC for various services represented as percentage of hours in a year.*

	NYISO-NYC			
Year	Off-line/Non-spinning Reserves (% of hours in a year)	Energy (% of hours in a year)	Spinning Reserve (% of hours in a year)	Regulation (% of hours in a year)
2007	53.3	14.7	0.1	31.9
2008	66.2	13.4	0.6	19.8
2009	79.9	8.7	0.3	11.2
2010	81.0	11.9	1.3	5.8
2011	87.4	8.9	2.0	1.7
2012	86.7	7.5	5.1	0.7
2013	83.0	12.1	4.1	0.8
2014	81.1	14.3	3.5	1.1
2015	81.6	13.5	2.8	2.1
2016	86.9	8.8	2.9	1.4

TABLE 5: *Utilization of the NCGT plant in NYISO-Long Island for various services represented as percentage of hours in a year.*

	NYISO-Long Island			
Year	Off-line/Non-spinning Reserves (% of hours in a year)	Energy (% of hours in a year)	Spinning Reserve (% of hours in a year)	Regulation (% of hours in a year)
2007	37.9	23.7	0.0	38.4
2008	49.0	22.8	0.4	27.9
2009	67.0	15.6	0.2	17.3
2010	71.6	20.8	1.0	6.6
2011	79.3	16.8	1.7	2.2
2012	79.0	15.8	4.4	0.9
2013	71.7	23.5	3.8	0.9
2014	75.0	20.5	3.1	1.4
2015	73.8	21.3	2.5	2.3
2016	80.7	15.2	2.4	1.7

TABLE 6: *Utilization of the NCGT plant in NYISO-Dunwood for various services represented as percentage of hours in a year*

	NYISO-Dunwood			
Year	Off-line/Non-spinning Reserves (% of hours in a year)	Energy (% of hours in a year)	Spinning Reserve (% of hours in a year)	Regulation (% of hours in a year)
2007	53.34	14.70	0.08	31.87
2008	66.20	13.44	0.59	19.76
2009	79.85	8.65	0.25	11.24
2010	80.96	11.93	1.31	5.80
2011	87.35	8.89	2.03	1.72
2012	86.75	7.49	5.10	0.66
2013	83.03	12.12	4.09	0.76
2014	81.08	14.35	3.48	1.08
2015	81.58	13.48	2.84	2.10
2016	86.92	8.78	2.88	1.42

TABLE 7: *Utilization of the NCGT plant in PJM-Chicago for various services represented as percentage of hours in a year*

	PJM-Chicago			
Year	Off-line/Non-spinning Reserves (% of hours in a year)	Energy (% of hours in a year)	Spinning Reserve (% of hours in a year)	Regulation (% of hours in a year)
2007	89.53	10.47		
2008	94.19	5.81		
2009	96.66	3.34		
2010	93.47	6.53		
2011	93.01	6.99		
2012	89.74	7.43	0.02	2.80
2013	86.78	3.73	0.72	8.77
2014	84.92	5.81	1.83	7.44
2015	78.34	8.39	5.14	8.13
2016	79.78	8.42	5.32	6.48
2017	83.80	4.41	4.20	7.59

TABLE 8: *Utilization of the NCGT plant in ERCOT-Houston for various services represented as percentage of hours in a year*

	ERCOT-Houston				
Year	Off-line/Non-spinning Reserves (% of hours in a year)	Energy (% of hours in a year)	Spinning Reserve (% of hours in a year)	Regulation-Up (% of hours in a year)	Regulation-Down (% of hours in a year)
2010	89.8	2.8	2.0	5.4	0.0
2011	86.3	6.6	3.4	3.5	0.1
2012	85.7	4.0	9.1	1.1	0.1
2013	82.6	4.9	11.0	1.2	0.2
2014	79.8	7.3	9.6	1.5	1.8
2015	86.4	4.5	7.3	0.8	0.9
2016	74.9	5.2	17.9	1.0	0.9
2017	73.9	7.0	15.0	2.9	1.3